ORIGINAL

MEMORANDUM

TO: Docket Control Center

FROM: Utilities Division EA for SMD

DATE: March 21, 2013

RE: SUPPLEMENT TO STAFF REPORT FOR RESOURCE PLANNING AND PROCUREMENT FOR 2011 AND 2012 (DOCKET NO. E-00000A-11-0113)

Attached is the Supplement to the Staff Report for the 2012 Integrated Resource Planning Assessment. This document contains company responses to questions posed by Commissioner Gary Pierce in his letter to the Docket, dated January 11, 2013, and Staff's analysis thereof.

Also attached is Staff's Proposed Amendment No. 1 that adds an additional Staff recommendation to the Proposed Order, filed on December 21, 2012.

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Originator: Rick Lloyd

SERVICE LIST FOR: Resource Planning and Procurement for 2011 and 2012
DOCKET NO. E-00000A-11-0113

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STAFF PROPOSED AMENDMENT NO. 1

TIME/DATE PREPARED: 10:00 am, March 21, 2013

COMPANY: Generic Docket – Integrated Resource Planning AGENDA ITEM NO.__

DOCKET NO(S). E-00000A-11-0113 OPEN MEETING DATE: April 9 & 10, 2013

Page 6, Line 22
INSERT NEW PARAGRAPH:

"Staff has further recommended that, in all future IRPs filed with the Commission, each load-serving entity with possible extra capacity include an alternative scenario in which any additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to the possible extra capacity. Each load-serving entity's IRP shall also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's preferred plan, including a comparison of projected retail rates."

Page 8, Line 4
INSERT NEW PARAGRAPH:

"IT IS FURTHER ORDERED that, in all future Integrated Resource Plans filed with the Commission, each load-serving entity with possible extra capacity shall include an alternative scenario in which any additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to the possible extra capacity. Each load-serving entity's IRP shall also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's preferred plan, including a comparison of projected retail rates."

MAKE ALL CONFORMING CHANGES

**** Make all conforming changes**

THIS AMENDMENT:

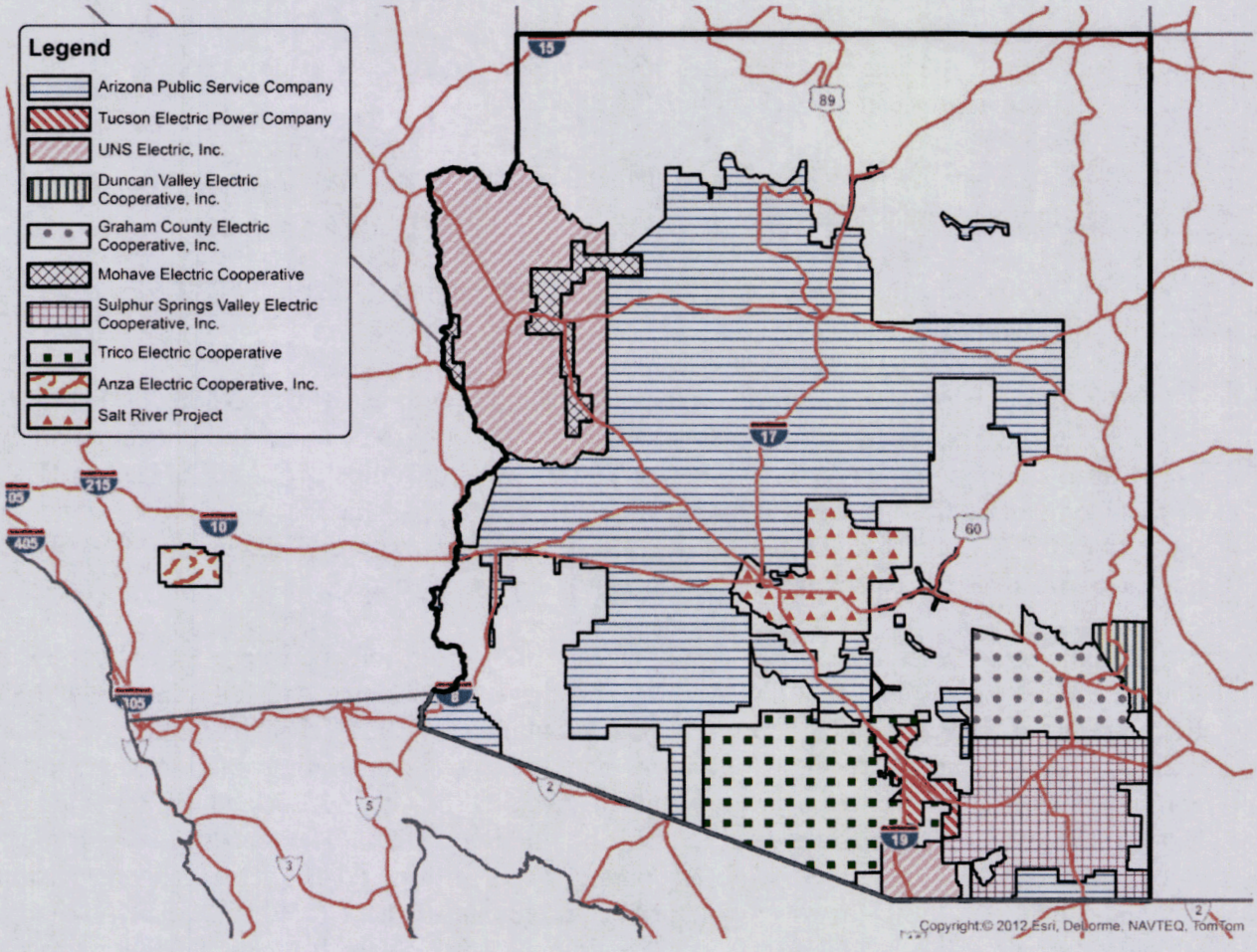
_____ Passed _____ Passed as amended by _____

_____ Failed _____ Not Offered _____ Withdrawn

SUPPLEMENT TO THE ASSESSMENT OF THE 2012 INTEGRATED RESOURCE PLANS OF THE ARIZONA ELECTRIC UTILITIES

ACC DOCKET NO. E-00000A-11-0113

MARCH 15, 2013



PREPARED ON BEHALF OF THE STAFF OF THE ARIZONA CORPORATION COMMISSION BY

GLOBAL ENERGY & WATER CONSULTING, LLC AND EVANS POWER CONSULTING, INC.

I. Introduction

On January 11, 2013, Commissioner Gary Pierce filed a letter to all parties in the 2012 IRP Docket requesting additional information regarding the current need, or lack thereof, for additional electric generation. Commissioner Pierce referred to the Commission's 7th Biennial Transmission Assessment ("BTA") recent finding that "As a result of current economic conditions, the statewide demand forecast for the 2012-2021 ten year planning period has shifted by about six years since the Sixth BTA (e.g., it will take about six years longer to reach the previous 2012 demand forecast level.)".

Given this, Commissioner Pierce seeks comprehensive answers to the following questions:

- Do the Arizona electric utilities have more generation capacity than they reasonably need and/or can put to beneficial use?
- If so, should the Commission suspend or alter in any way utility directives to obtain more generation capacity?
- Does the entire Western Electricity Coordinating Council ("WECC") have extra generating capacity?

Commissioner Pierce requested that the utilities respond to specific questions by February 1, 2013. He further requested that Staff be given an opportunity to evaluate and docket its analysis of the utilities' responses. To date, Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNSE"), Arizona Electric Power Cooperative, Inc. ("AEPCo"), Salt River Project ("SRP") and Western Resource Advocates ("WRA") have provided information in response to Commissioner Pierce's request.

Commissioner Pierce's letter highlights a natural tension between the Commission's Integrated Resource Planning ("IRP") rules and the Commission's Annual Renewable Energy Requirement ("ARER") and Energy Efficiency Standard ("EES"). The IRP rules require that each load-serving entity develop long-term plans that consider, among other factors, the best combination of expected costs and associated risks, while the ARER and EES mandate the acquisition of specific resources over a prescribed period of time. The tension between the IRP rules and the ARER and EES is most apparent when utilities do not have growing customer demand. It is one thing for the regulatory requirements of the ARER and EES to determine which resources will be acquired to meet growing customer needs. It is another thing altogether for those regulatory mandates to require the acquisition of resources when new resources may not be needed.

This Supplement addresses the issues raised by Commissioner Pierce and the responses filed by APS, TEP, UNSE, AEPCo, SRP and WRA. Staff finds, based upon the information provided, that TEP and UNSE do not currently have extra capacity, that is, capacity that is greater than the minimum required level of capacity. In fact, TEP and UNSE are seeking additional capacity in 2013. However, APS and AEPCo currently have extra capacity. APS is likely to continue to have extra capacity through 2015. After 2015, projected APS load growth eliminates the extra

capacity. AEPCo currently has extra capacity and will continue to have extra capacity through 2014.

Staff recommends that in all future IRPs filed with the Commission, each load-serving entity with possible extra capacity include an alternative scenario in which any additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to possible extra capacity. Each utility's IRP should also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's preferred plan, including a comparison of projected retail rates.

II. Information Provided in Response to Commissioner Pierce's Letter

The following specific questions were raised by Commissioner Pierce in his January 11, 2013 letter:

1) What is the existing reserve capacity for each load-serving entity, and how does that compare with the reserve capacity for that entity over the past twenty years?

2) What are the load-serving entities' existing off-system sales and how do those sales compare with previous sales over the past twenty years?

3) What is the outlook for off-system sales for each load-serving entity in the future?

4) What has been the aggregate capacity factor (actual load served divided by the system load serving capacity) for each load-serving entity over the last twenty years for the following:

   a. at system peak load for the year,
   b. at average load during the peak month,
   c. at average annual load,
   d. at average load during the lowest load month?

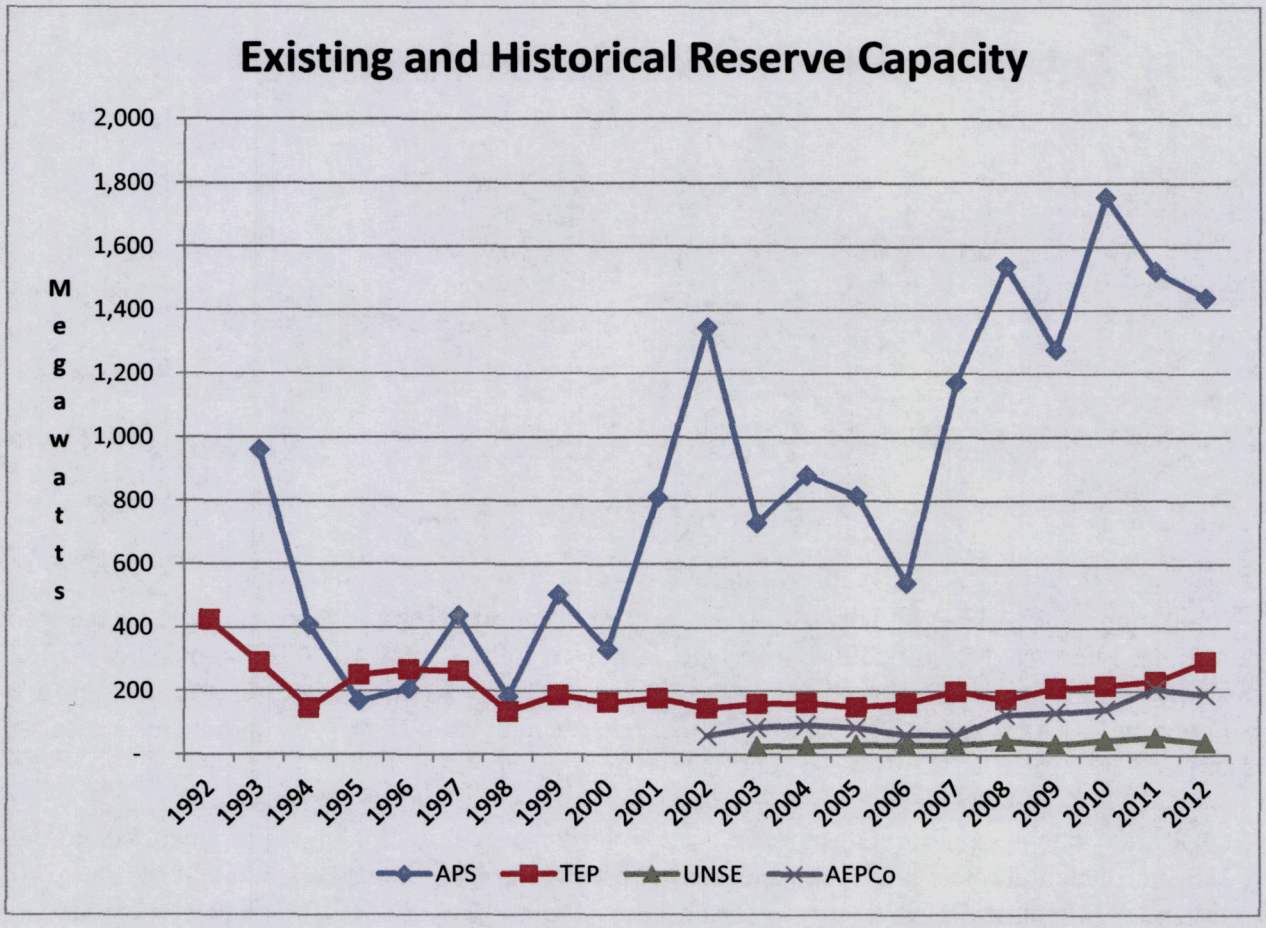
5) Are there reasons to believe that maintaining and even increasing the existing extra reserve capacity in the short-term will mitigate rate increases in the future when an eventual economic recovery will inevitably increase electric demand?

Each of these questions and the responses received from the parties are addressed below.

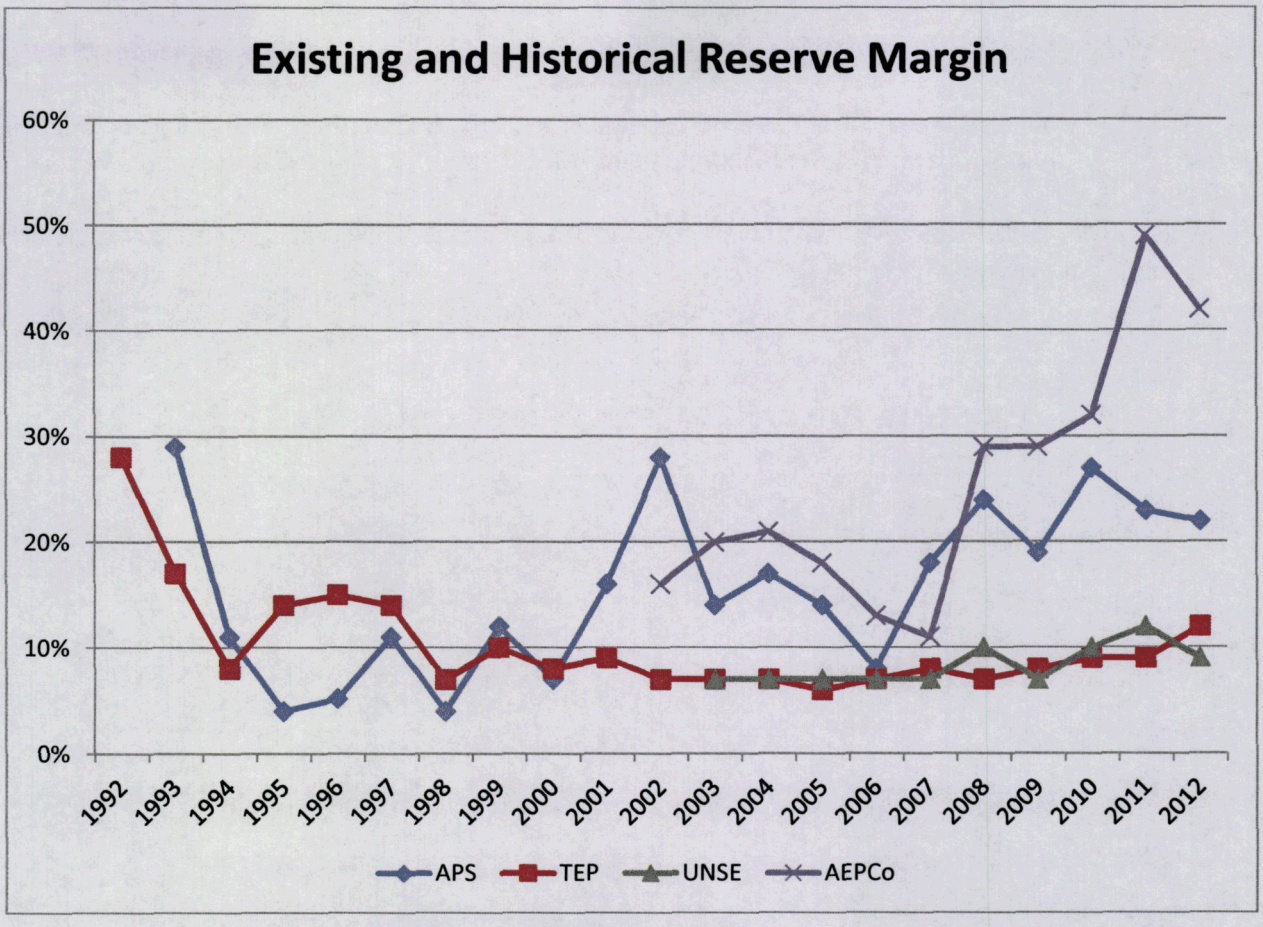
A. Existing and Historical Reserve Capacities

1) What is the existing reserve capacity for each load-serving entity, and how does that compare with the reserve capacity for that entity over the past twenty years?

APS, TEP, UNSE and AEPCo have provided the requested reserve capacities, which are shown on the following chart:



The four load-serving entities also provided reserve margins, which present the reserve capacities as a percentage of peak customer demand:



Although APS, TEP and UNSE target a 15% planning reserve capacity, actual reserve margins have varied significantly from the target (which is typical). TEP and UNSE 2012 reserve margins are well below the 15% target, while the APS and AEPCo reserve margins are well above 15% in recent years. The APS 2012 reserve margin is 22%. APS anticipates a reserve margin of 28% in 2013. AEPCo's recent reserve margins are even higher.

APS attributes existing extra reserves primarily to two factors – the recent economic recession, which dramatically reduced load growth, and the inclusion of call options. Call options are purchase power contracts which allow the purchaser (APS) to request capacity on very short notice. Typical call options are inexpensive to own, but costly to exercise. They provide capacity that is only used in emergency situations, and thus do not cause APS generators to be idled. Call options are typically only called upon during a few summer hours. Excluding call options, the APS reserve capacity would be reduced by 650 megawatts, the 2013 reserve margin would be reduced from 28% to 19% and the 2012 reserve margin would be reduced from 22% to approximately 14%.

Under the APS AZ Sun Program, APS has added 100 megawatts of solar generating capacity and plans to add an additional 100 megawatts of solar generating capacity in 2013 through 2015 through a competitive procurement process. According to the APS 2012 IRP, 24 megawatts were added under the program in 2012 and an additional 49 megawatts are planned for 2013.

Elimination of this program would have only a minor impact on the APS reserve margin, e.g., the 2012 reserve margin would be reduced from 22% to 21.7%.

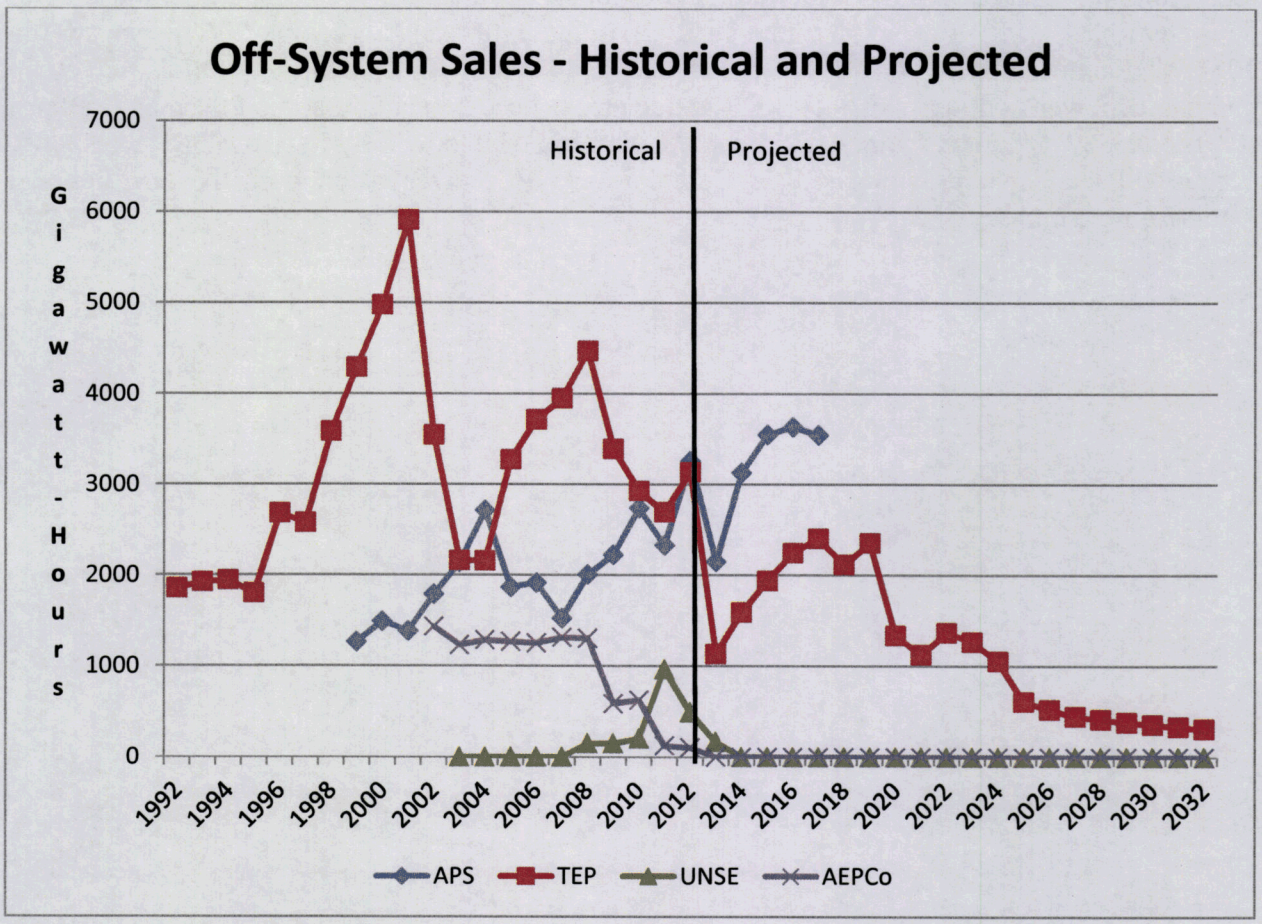
SRP, which is not subject to the Commission's IRP rules, voluntarily responded to Commissioner Pierce's letter. In his letter, Commissioner Pierce included information provided by SRP that was included in the Staff Report, namely that SRP had a retail peak demand of 6,369 megawatts in 2011 and resources available to serve load of 8,284 megawatts, implying extra capacity of more than 2,000 megawatts. SRP explains in response that its total system peak load in 2011 was 7,072 megawatts, which is its retail peak demand plus firm and contingent sales for resale, interruptible industrial sales, surplus sales, and exchange deliveries. In addition, SRP says that operating reserves in 2011 required an additional 900 megawatts of capacity at the time of its system peak. SRP states that although it had some extra capacity (some 200 megawatts) in 2011, that extra capacity no longer exists due to load growth and the expiration of certain purchased power contracts. In fact, SRP anticipates a need to acquire some 200 megawatts of short-term power purchases in 2013. However, Staff is unable to fully evaluate SRP's response because SRP did not provide the data Commissioner Pierce requested from the jurisdictional load-serving entities.

B. Off-system Sales

2) What are the load-serving entities' existing off-system sales and how do these sales compare with previous sales over the past twenty years?

3) What is the outlook for off-system sales for each load-serving entity in the future?

APS, TEP, AEPCo and UNSE have provided the requested off-system sales, as shown on the following chart:



Historically, TEP's off-system sales have varied dramatically over the past twenty years, and in the most recent year (2012) are close to the historical average level. APS has produced high volumes of off-system sales, especially in recent years. APS' off-system sales in 2012 were nearly a million megawatt-hours higher than the historical average (2,327,500 megawatt-hours). UNSE has only recently begun to have significant levels of off-system sales. AEPCo's off-system sales have declined in recent years.

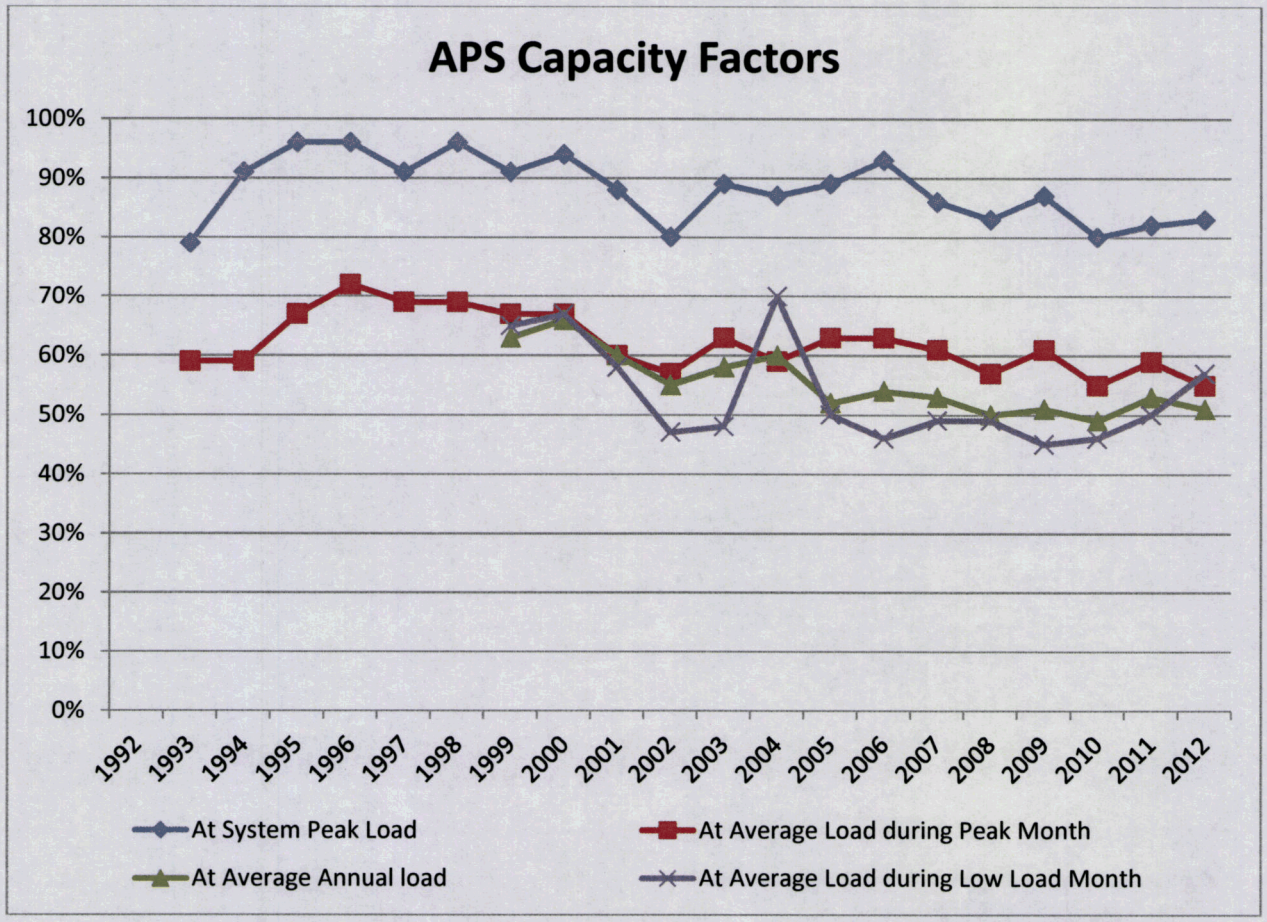
Looking forward, both APS and TEP forecast increasing off-system sales in the near-term, with the level of sales tapering off later in the decade. UNSE and AEPCo do not forecast significant off-system sales.

C. Historical Capacity Factors

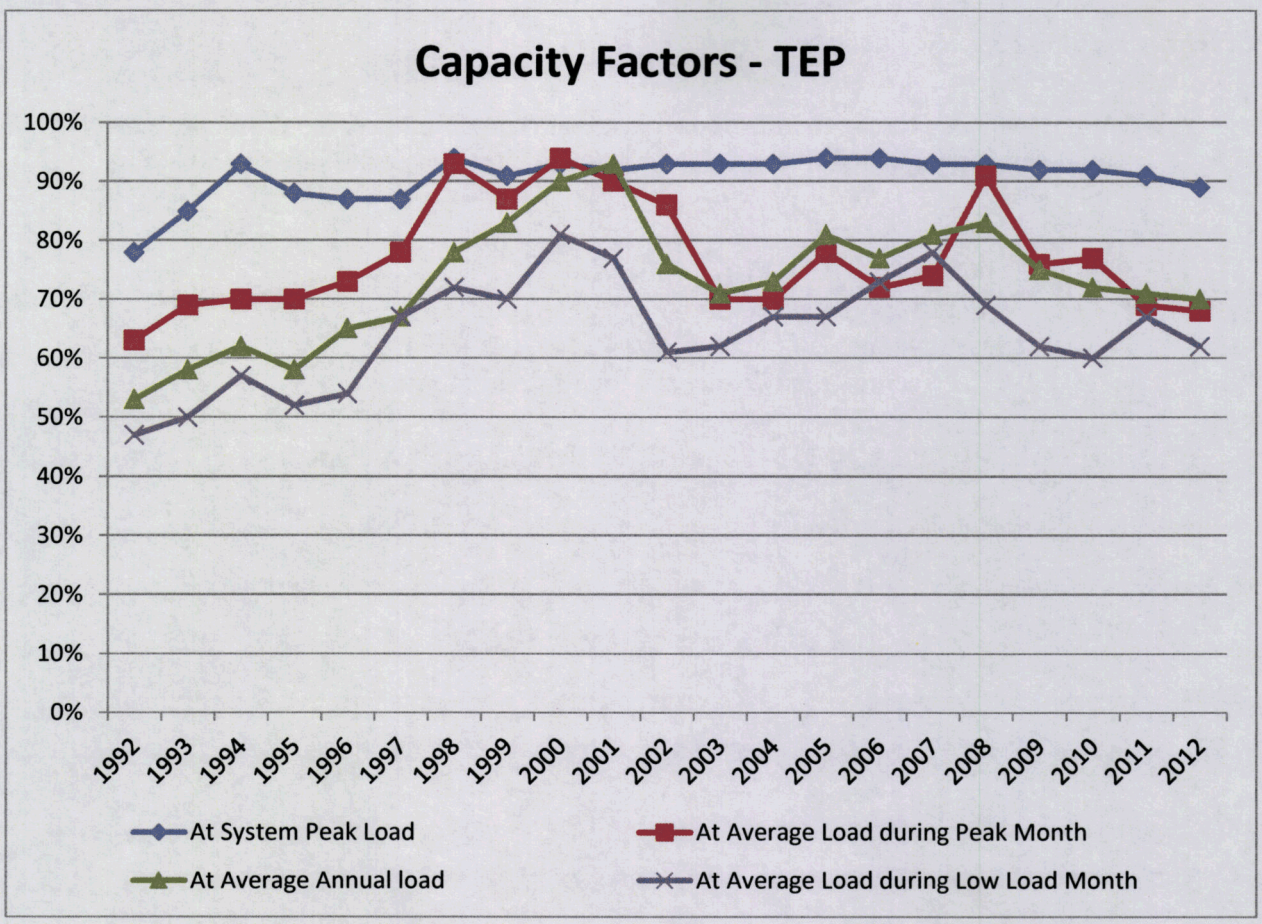
4) What has been the aggregate capacity factor (actual load served divided by the system load serving capacity) for each load-serving entity over the last twenty years for the following:

   a. at system peak load for the year,
   b. at average load during the peak month,
   c. at average annual load,
   d. at average load during the lowest load month?

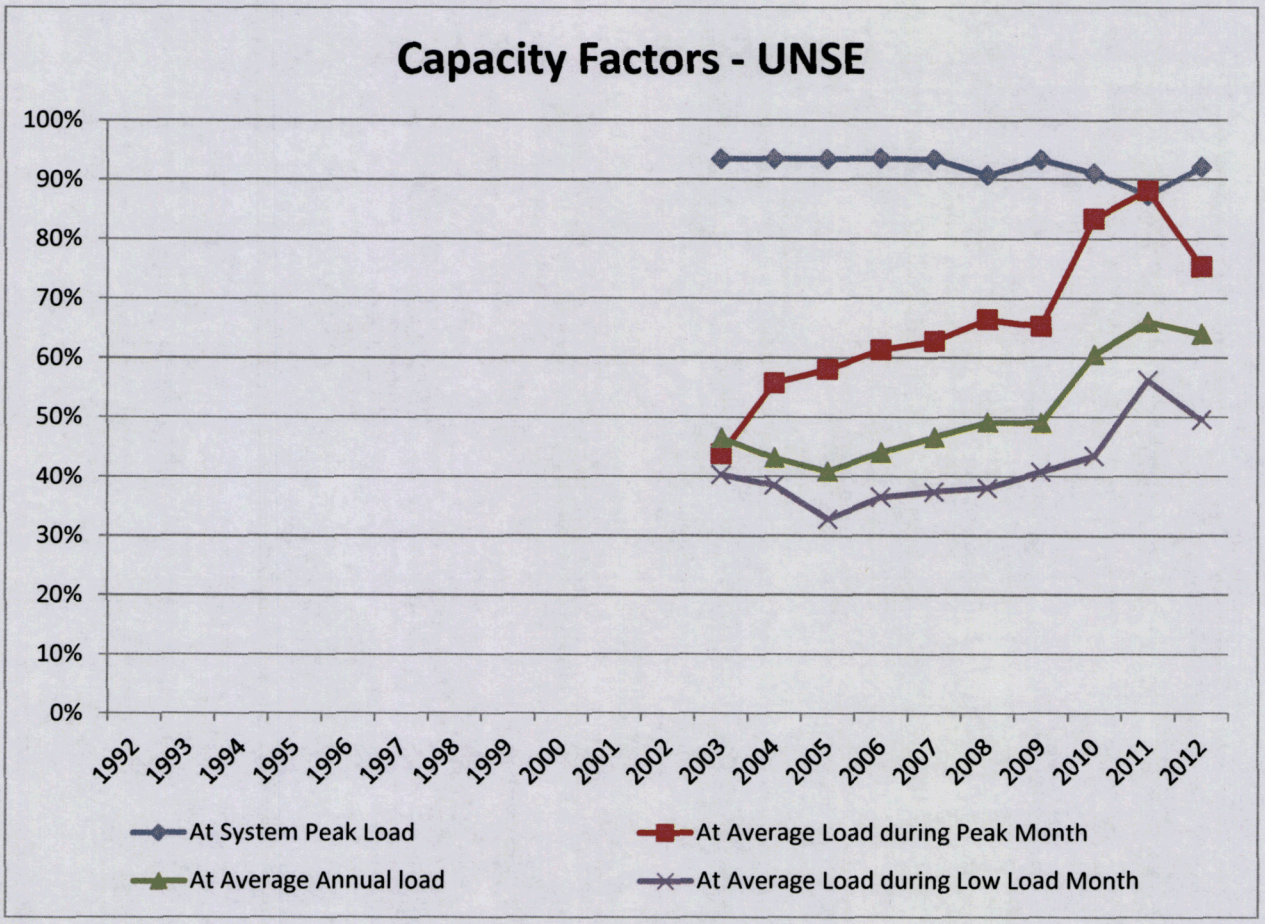
APS, TEP, AEPCo and UNSE have provided the requested information, as shown on the following charts:



This information indicates that the utilization of APS resources has declined slightly in recent years. Although this decline could be the result of extra reserve capacity, it could also be caused by other factors, such as the addition of peaking generation facilities (which have lower capacity factors) or the increase in system peak demand relative to other hourly loads.



As with APS, recent TEP capacity factors are trending slightly downward.


Capacity Factors - UNSE
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
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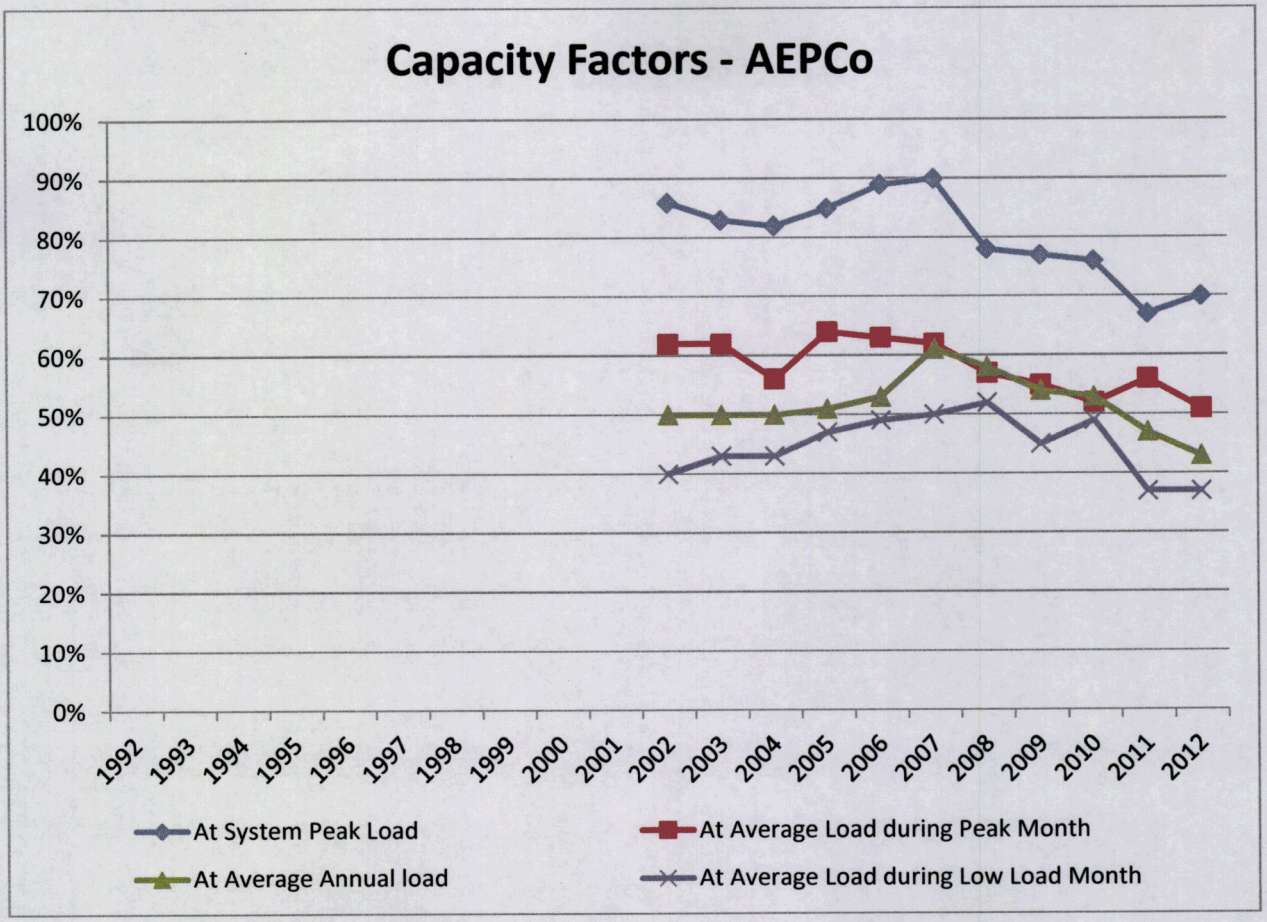
2010
2011
2012
At System Peak Load
At Average Load during Peak Month
At Average Annual load
At Average Load during Low Load Month



AEPCo capacity factors have been declining in recent years.

D. Rate Impacts of Extra Reserve Capacity

5) Are there reasons to believe that maintaining and even increasing the existing extra reserve capacity in the short-term will mitigate rate increases in the future when an eventual economic recovery will inevitably increase electric demand?

As discussed above, APS currently has extra reserve capacity. In APS' response to Commissioner Pierce's letter, APS states that it "believes our reserve margin is reasonable under today's circumstances and that the current generation fleet is being used efficiently." Specifically in response to Commissioner Pierce's question (5), APS states that "Reducing reserve margin will not necessarily mitigate rate increases" and "reserves beyond the 15 percent minimum do not necessarily show either an efficient or inefficient generation portfolio."

TEP and UNSE do not currently have extra reserve capacity. However, both TEP and UNSE state that increasing existing reserve requirements in the short-term would put upward pressure on customer rates today. TEP and UNSE also claim that, if more generating capacity is required in the near future, a long-term power purchase agreement or acquisition of an existing merchant plant would likely mitigate any future rate increases.

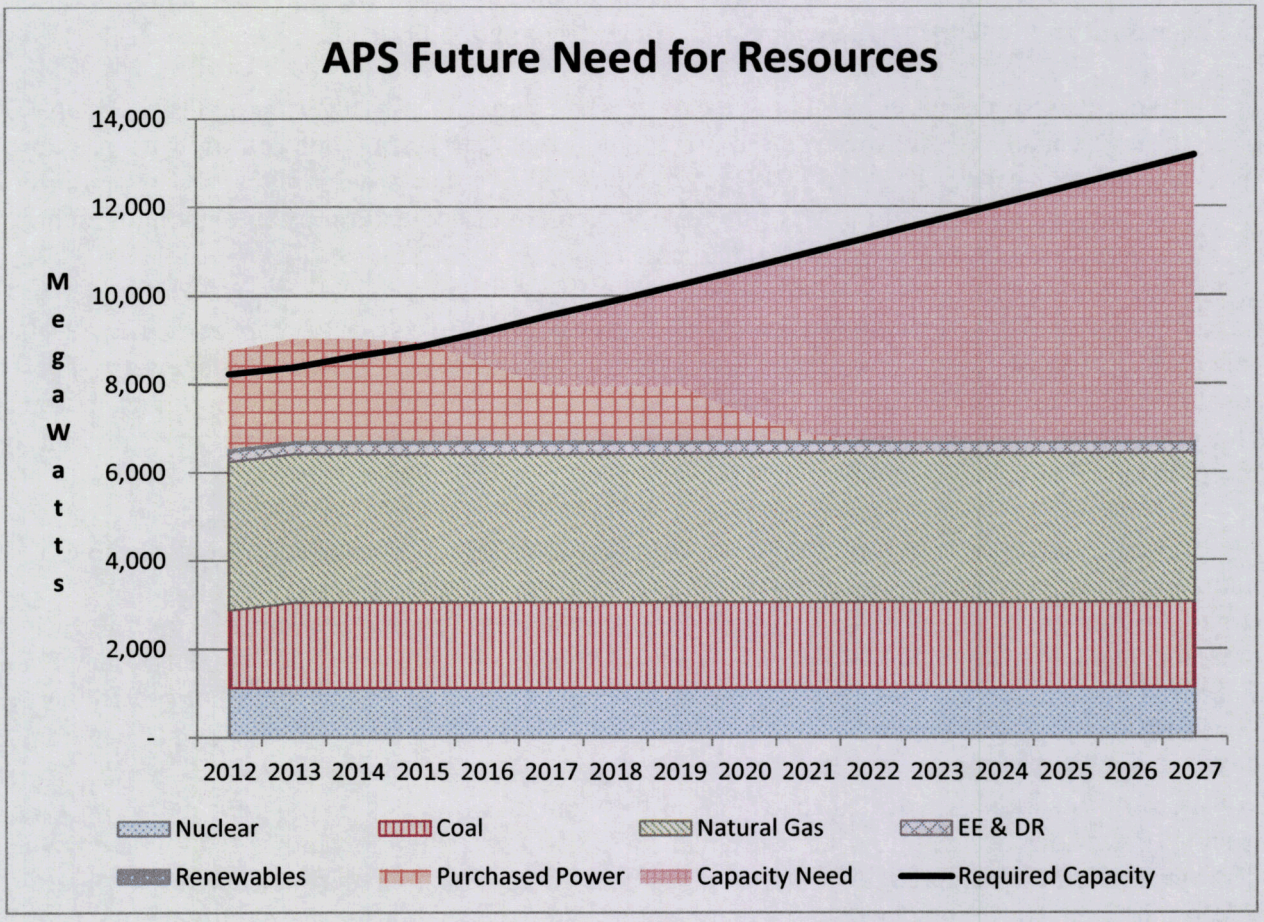
SRP, in discussing the management of costs of maintaining a reserve margin, points out the role of SRP's older, less-efficient natural gas generators, which total some 800 megawatts. These resources generally have very low capacity factors relative to modern generating units, but are almost completely depreciated and thus represent a very cost-effective means of maintaining reserve capacity.

In AEPCo's response, AEPCo states that although in certain circumstances, it is possible that maintaining or even increasing reserves might be a viable, cost-effective way to meet future expected load growth, AEPCo does not need to plan to build or acquire any new resources for the foreseeable future. AEPCo is not subject to the requirements of the Annual Renewable Energy Requirement, the Distributed Renewable Energy Requirement, or the Energy Efficiency Standard.

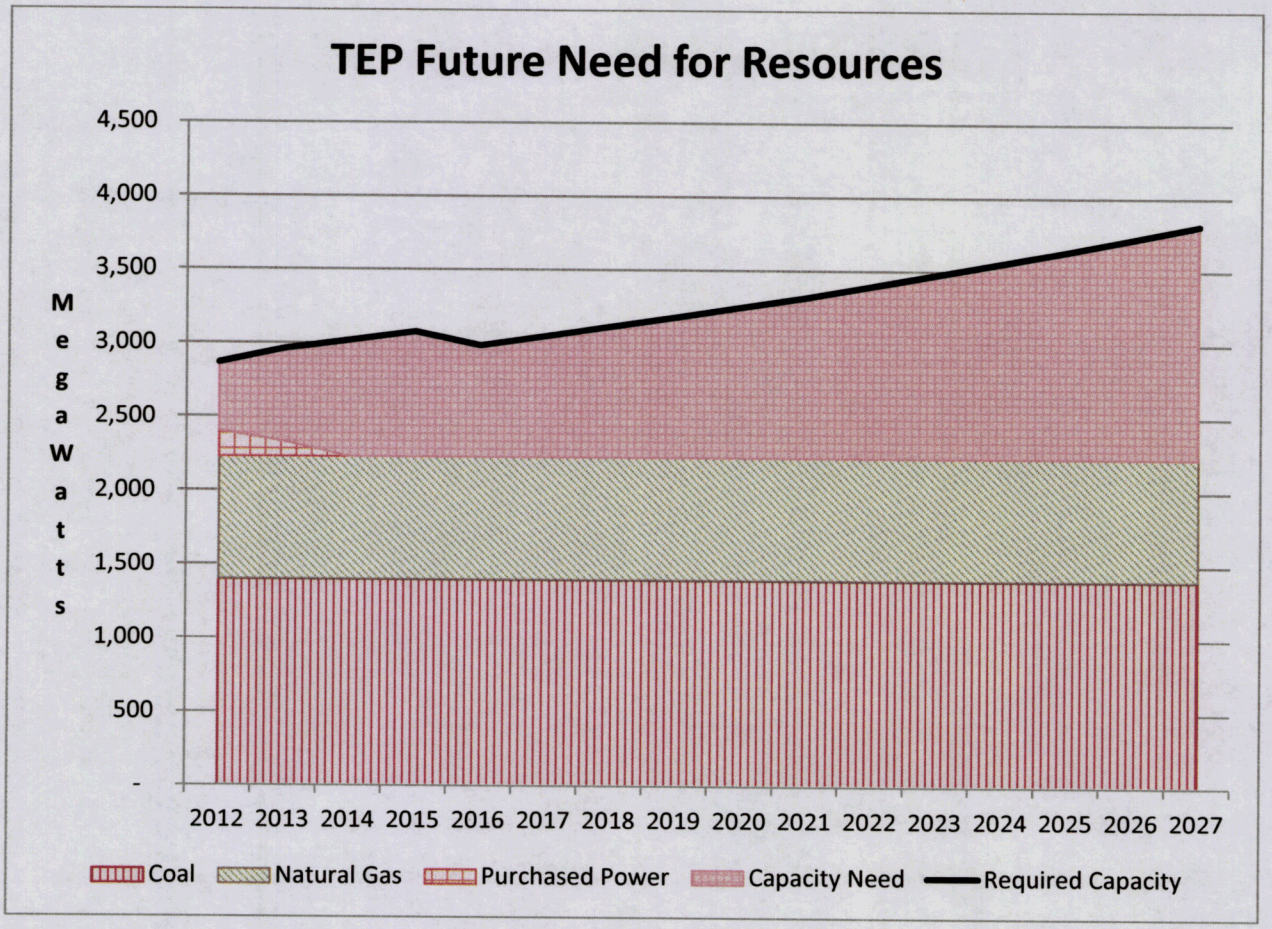
Western Resource Advocates states that, if the Commission finds that there is extra capacity, it should consider accelerating the retirement of coal-fired generation rather than delaying the deployment of new technologies, such as renewable generation and energy efficiency programs. Where older coal-fired power plants face potential increased fuel costs and environmental costs, renewable energy and energy efficiency produce little or no air emissions and even reduce environmental impacts.

III. Future Need for Additional Resources

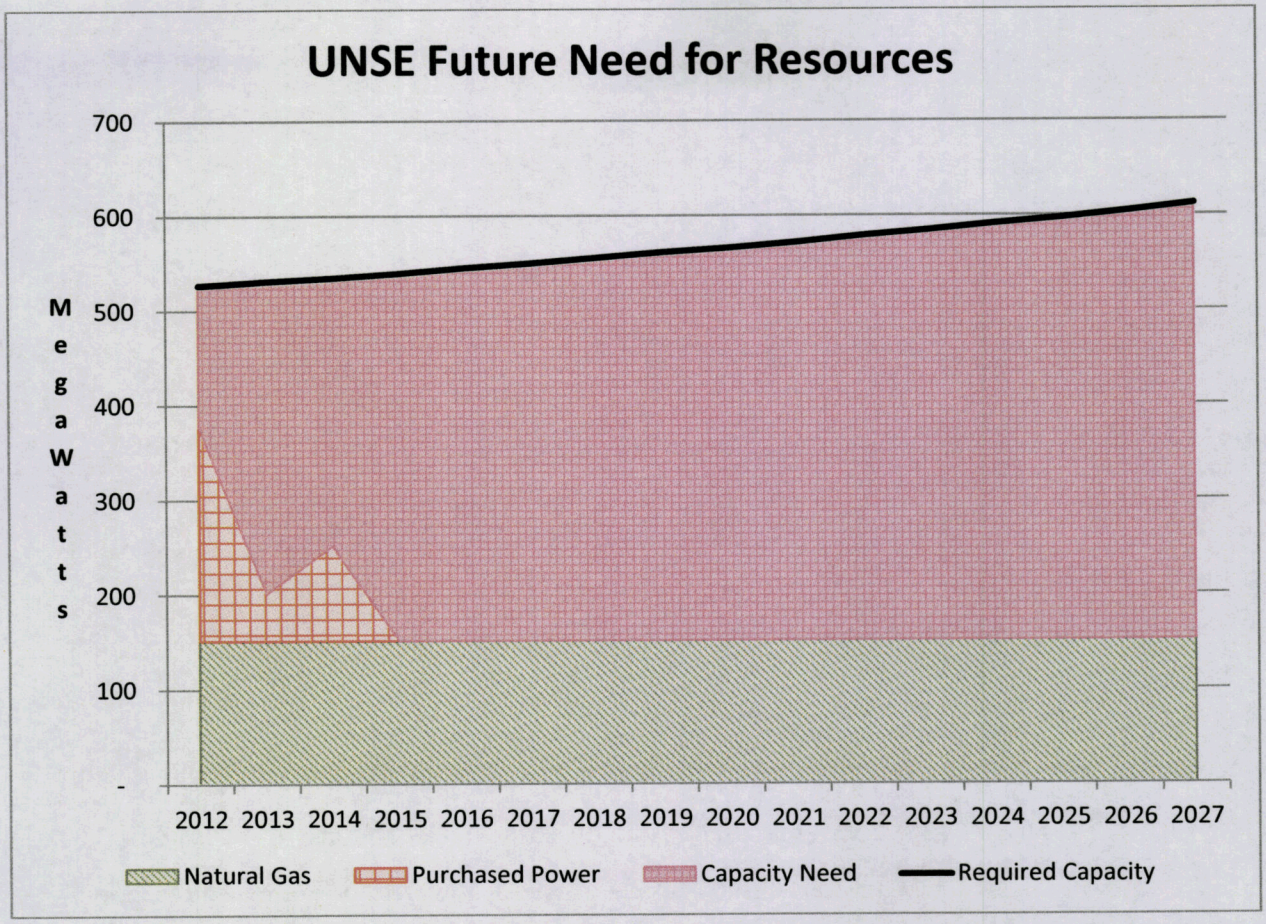
The future need for additional resources for each of the load-serving entities is driven by the annual forecast of peak demand (the highest one-hour need for electricity) and the planning reserve margin. APS, TEP and UNSE each utilize a 15% planning reserve margin, which equates to an additional capacity requirement of 150 megawatts for each 1,000 megawatts of forecasted peak demand. Comparing the on-peak capability of existing resources to the forecasted peak demand plus the planning reserve requirement reveals the need for additional resources for each load-serving entity. The following charts utilize information from the 2012 IRPs to show this comparison and the resulting needs for additional resources.



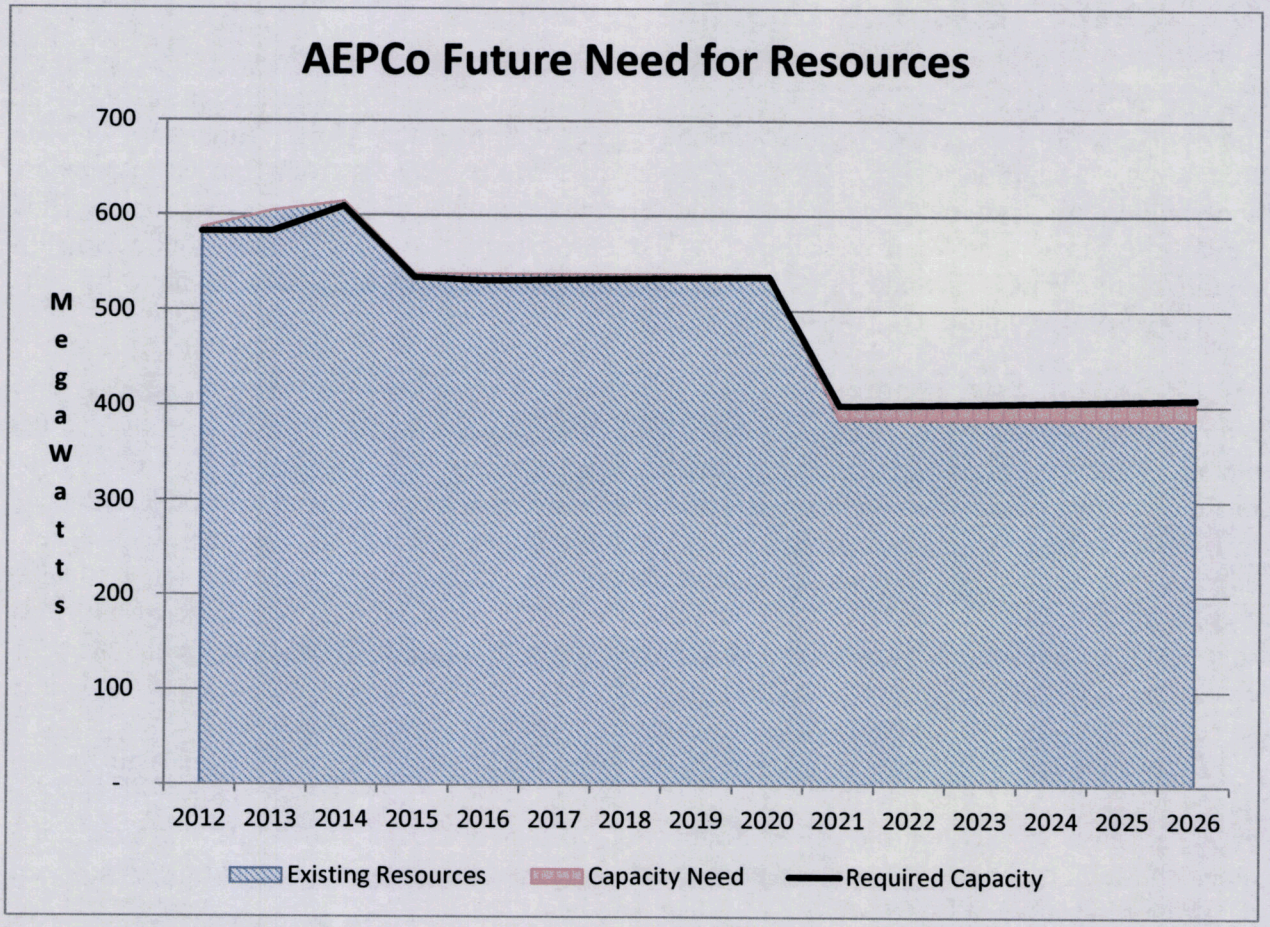
APS does not show a need for additional resources until 2016. However, it is important to note that purchased power contracts, including call options, are contributing to this extra capacity in the years 2012-2015. After 2015, APS' need for additional resources grows from over 700 megawatts in 2016 to nearly 6,500 megawatts in 2027.



TEP has needs for additional resources in all years of the planning period, growing from 467 megawatts in 2012 to 1,588 megawatts in 2027.



UNSE also shows a need for additional resources in all years, growing from 149 megawatts in 2012 to 459 megawatts in 2027.



AEPCo has a small surplus of capacity through 2021, followed by a need for additional resources of 16 to 22 megawatts in subsequent years.

IV. Western Electricity Coordinating Council

The Western Electricity Coordinating Council ("WECC") is geographically the largest and most diverse of the eight regional entities that comprise the North American Electric Reliability Corporation ("NERC"). WECC's service territory extends from Canada to Mexico, and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and substantially all of the 14 western states. The Desert-Southwest sub-region of the WECC includes all of Arizona, the southeast corner of Nevada, most of New Mexico and a small portion of western Texas.

According to NERC's 2012 Long-Term Reliability Assessment, the Desert-Southwest sub-region of the WECC will have extra capacity from 2013 through 2022. NERC anticipates that the planning reserve margin for the Desert-Southwest will decline from 46.57% in 2013 to 29.09% in 2022[1]. This information indicates that load-serving entities with extra capacity will have difficulties selling that extra capacity within the sub-region, and also indicates that load-serving entities that are planning on purchasing capacity and energy from other parties are likely to have ample opportunities for making such purchases within the sub-region. The Desert-Southwest sub-region includes Arizona, so extra reserves in the sub-region include those of the Arizona electric utilities.

Across the complete span of the WECC, NERC forecasts that reserve margins will remain near 15% from 2017 through 2022[2]. That is, across the WECC, there is essentially no expected extra capacity. So although the Desert-Southwest sub-region is expected to have extra capacity, other sub-regions of the WECC are expected to have capacity shortfalls, creating a balanced picture for the entire WECC.

[1] Page 255, NERC 2012 Long-Term Reliability Assessment
[2] Page 57, NERC 2012 Long-Term Reliability Assessment

V. Conclusions

A. Do the Arizona electric utilities have more generation capacity than they reasonably need and/or can put to beneficial use?

TEP and UNSE do not currently have extra capacity. In fact, TEP and UNSE are seeking additional capacity in 2013. However, APS and AEPCo currently have extra capacity.

APS's extra capacity includes 650 megawatts of call options, which are purchase power contracts that are called upon only when needed. This means that the APS extra capacity situation is somewhat exaggerated. However, with required additions of renewable capacity and energy efficiency programs, APS is likely to continue to have extra capacity through 2015. After 2015, projected APS load growth eliminates the extra capacity.

Although AEPCo currently has extra capacity, the extra capacity will no longer exist after 2014. AEPCo is not subject to the Commission's requirements to add additional renewable capacity and energy efficiency programs.

B. If so, should the Commission suspend or alter in any way utility directives to obtain more generation capacity?

Given the answer to question (A) above, the question only applies to APS. In the APS response to Commissioner Pierce's letter, APS states that "... reserve margin should only be one metric considered when making resource decisions" and "... reserves beyond the 15 percent minimum do not necessarily show either an efficient or inefficient portfolio."

Staff agrees with APS, in that added capacity required by Commission rules (renewables and energy efficiency programs) that may exacerbate the extra capacity carried by a load-serving entity do not necessarily have a negative impact. Further analysis would be required to ascertain the specific impacts of the extra capacity. The question is complex and can only be thoroughly answered through the analyses that are normally carried out in the development of an IRP. During the development of future IRPs, the load-serving entities could assess the impact of these extra reserves on total projected costs and projected retail rates.

C. Does the entire Western Electricity Coordinating Council ("WECC") have extra generating capacity?

According to NERC's 2012 Long-Term Reliability Assessment, the entire WECC does not, and is not predicted to have, extra generating capacity through 2022.

VI. Recommendations

Staff recommends that, in all future IRPs filed with the Commission, each load-serving entity with possible extra capacity include an alternative scenario in which any additions of capacity, mandated or not, that contribute to the possible extra capacity are delayed until such additions do not contribute to possible extra capacity. Each utility's IRP should also include a comparison of all projected costs under this alternative scenario relative to the load-serving entity's preferred plan, including a comparison of projected retail rates.